BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2020-1-E

In the Matter of	)	
Annual Review of Base Rates	)	**REBUTTAL TESTIMONY OF**
for Fuel Costs for	)	**JAMES J. MCCLAY, III FOR**
Duke Energy Progress, LLC	)	**DUKE ENERGY PROGRESS, LLC**

TABLE OF CONTENTS

I. INTRODUCTION 3

II. PURPOSE AND SCOPE 4

III. NATURAL GAS SUPPLY AND TRANSPORTATON CAPACITY MANAGEMENT 6

IV. LOAD FACTOR UTILITIZATION ANALYSIS 9

V. SUFFICIENCY OF CAPACITY TO SERVE COMBINED CYCLE UNITS 13

VI. MONETIZATION OF UNUSED CAPACITY 14

VII. DISCOVERY AND PROCEDURAL MATTERS 17

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is James J. McClay, III. I am Director of Trading for Duke Energy Corporation ("Duke Energy"), and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERENCE.

A. I received a Bachelor's degree in Business Administration from St. Bonaventure University. I have worked in the energy industry for 21 years. Prior to that, I had approximately 13 years of experience as a US Government Fixed Income Securities Trader with various financial firms including Paribas Capital Markets and Cantor Fitzgerald. I joined Progress Energy in 1998 as an Energy Trader. I was promoted to Manager of Power Trading and held that position until 2003. From 2003 through 2007, I was Director of Power Trading and Portfolio Management for Progress Energy Ventures, Progress Energy's unregulated affiliate. March 2007 through late 2008, I was Director of Power Trading for Arclight Energy Marketing upon the sale of Progress Energy Ventures to Arclight. Since returning to Progress Energy in March 2009, I've held various managerial roles including Manager of Gas and Oil Trading for both Progress Energy and subsequently Duke Energy following the merger of Duke Energy and Progress Energy in 2012. I assumed my current position as Director of Trading in May 2019. As Director of Trading, I manage the organization responsible for the natural gas trading, optimization and scheduling functions for the regulated gas-fired generation assets in the Carolinas, Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP" or the "Company"), Duke Energy Florida, Duke Energy Indiana and Duke Energy Kentucky (collectively, the "Utilities"), as well as the organization responsible for power trading for the Utilities. Additionally, I oversee the execution of the Utilities' financial hedging programs, fuel oil procurement, and emissions trading.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to: 1) provide additional background on the management of natural gas supply and transportation capacity on behalf of DEP and DEC (collectively, the "Companies") and 2) respond to testimony and recommendations offered by Mr. Gregory Lander on behalf of Southern Alliance for Clean Energy and South Carolina Coastal Conservation League ("SACE/CCL").

Q. WHAT IS THE PURPOSE OF THIS PROCEEDING?

A. It is my understanding that the purpose of this fuel proceeding is to review the Company's proposed fuel rates.

Q. HAS WITNESS LANDER RECOMMENDED ANY CHANGES TO THE FUEL RATES PROPOSED BY THE COMPANY?

A. No. Mr. Lander has not recommended any changes to the Company's proposed fuel rates. His testimony focuses on the Companies' contracted pipeline capacity utilization; sufficiency of their existing capacity to reliably serve their generation needs; and the lack of monetization of "idle" capacity.

Q. DO YOU AGREE WITH MR. LANDER'S TESTIMONY AND RECOMMENDATIONS[1]?

A. No. As discussed in more detail below, I disagree with Mr. Lander as to his primary conclusions and recommendations. First, due to technical issues inherent in operational data estimates, Mr. Lander's load factor utilization analysis does not include all gas flows and burns from the review period and is therefore understated. Second, the Companies do not have sufficient firm capacity to serve their gas generation requirements as they currently rely on a single source pipeline with an inadequate amount of firm transportation ("FT") and increasing operational restrictions. Third, the Companies do not have extra or "idle" capacity to monetize by releasing it to the market. Instead, as part of an overall gas supply strategy intended to benefit customers, the Companies purposely maintain FT capacity throughout the gas day to address intraday needs, late-cycle storage adjustments, and post cycle penalty mitigation. Due to their limited amount of FT, the Companies' strategy is to focus on protecting the customer from pipeline imbalance penalties of $50/dth rather than releasing limited daily capacity in exchange for nominal reward. Fourth, the Company has endeavored to provide information consistent with that specified in the Commission's order in the 2019 DEC fuel proceeding and with the data requests submitted by SACE/CCL. This information is based on operational estimates and is not "revenue-grade," and should not be used in making recommendations or decisions that impact customer rates. Finally, it is my understanding that the procedural schedule does not need to be adjusted as SACE/CCL submitted their first data request on April

[1] Direct Testimony of Gregory M. Lander p. 4, line 18.

10, 2020 which was several weeks before the Company's filing date of April 27, 2020 for direct testimony. I also understand that SACE/CCL had no substantive follow-up discovery requests, apart from correcting a previously submitted data request.[2]

III. NATURAL GAS SUPPLY AND TRANSPORTATON CAPACITY MANAGEMENT

Q. HOW IS NATURAL GAS SUPPLY AND DAILY FIRM TRANSPORTATION MANAGED BY THE COMPANIES?

A. Under the Affiliate Asset Management and Delivered Supply Agreement ("AMA") implemented in January 2013, DEP assigns its gas transportation and storage assets to DEC.[3] As the designated Asset Manager, DEC manages transportation and procurement activities and optimizes the value of gas supply resources on a combined basis for both DEC and DEP. Each month the total costs, excluding station specific fixed transportation costs, are allocated across the two utilities according to the methodology prescribed under the AMA.

Q. HOW IS NATURAL GAS DELIVERED TO THE COMPANIES' GENERATING FACILITIES?

A. The Companies procure long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. It is important to note that in the Carolinas, the Transcontinental Gas Pipe Line Company, LLC ("Transco") is the sole source of interstate transportation capacity for the Companies' natural gas generation portfolio.

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[2] SACE/CCL sent a follow-up discovery request on May 5, 2020 to correct an error in its previously submitted request.

[3] The AMA was approved by the Public Service Commission of South Carolina in Order No. 2012-955 issued in Docket No. 2011-158-E.

Given the Companies' limited amount of contracted firm transportation, the Companies participate in the capacity release market in order to purchase shorter term firm interstate pipeline capacity, if available and economic, but the Companies primarily procure third party delivered gas to supplement their forecasted gas generation demand.

Q. PLEASE DESCRIBE HOW MUCH LONG-TERM FIRM CAPACITY THE COMPANIES CURRENTLY HAVE UNDER CONTRACT AND ITS PRIMARY USES.

A. Currently, the Companies have 434,500 dths/day of FT capacity under contract with Transco. This FT capacity provides the underlying framework for the Companies' strategy to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Companies to procure lower cost natural gas supply from Transco Zones 3 and 4 and transport it to Transco Zone 5 for delivery to the Carolinas' generation fleet. Transco Zones 3 and 4 intersect with multiple pipelines and have excellent supply liquidity and lower gas prices compared to Zone 5. Second, this FT capacity allows the Companies to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, this FT capacity allows the Companies to mitigate penalties associated with pipeline imbalances. Customers receive the benefit of each these aspects of the Companies' FT: lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Due to their location, the Companies currently do not have an interstate pipeline alternative, nor does Transco have the capacity for the Companies to contract for additional long-term FT to manage the supply deliverability needed for current gas demand.

Q. HAVE THERE BEEN ANY CHANGES TO THE INTERSTATE PIPELINE TARIFF THAT HAVE CONSTRAINED THE COMPANIES' ABILITY TO MANAGE NATURAL GAS SUPPLY DELIVERIES TO THEIR GAS GENERATION FLEETS?

A. Yes, Transco recently implemented two-sided Operational Flow Orders ("OFOs") by which pipeline tolerances for both high and low burns are simultaneously in effect. Shippers' total gas day burns must stay between the bracketed tolerance levels or be subject to a $50 per dekatherm ("dth") penalty for volumes exceeding the tolerances. Additionally, there have been several operational changes affecting daily imbalance management. Effective July 1, 2019, Transco implemented a revised tariff, approved in FERC Docket No. RP18-314-000,[4] that includes restrictions that further constrain the Companies' operational flexibility by limiting intra-day swings that cause daily imbalances, particularly during the overnight hours and weekend days when the natural gas markets are closed, and the pipeline delivery schedule is fixed. In particular, the tariff revises Transco's Priority Of Service ("POS"), updating restrictions and charges and penalties for unauthorized daily overrun or "No Notice

[4] *See* FERC Docket No. RP19-1225-000, the docket in which Transco's compliance filing was filed and approved; *see also* FERC Docket No. RP18-314-000; *Transcontinental Gas Pipe Line Company, LLC*, 164 FERC ¶ 61,174 (Sept. 7, 2018) (approving Transco's proposed tariff revisions).

Swing" services above a specified daily tolerance: 1) 0 - 3.5% of total delivered supply from the period October through April, and 2) 0 - 5% of total delivered supply for the period May through September. The new charges and penalties for overruns above a customer's total contract quantity of FT are up to $50 per dth or three times the high Common Reference Spot Price for the month, whichever is higher.

Prior to updating the POS, Transco had, over the last several years, increased the use of daily OFOs to constrain and penalize customer swings that create daily pipeline imbalances.

Q. SINCE THE IMPLEMENTATION OF THE PRIORITY OF SERVICE REVISIONS, HAS THE TRANSCO PIPELINE HAD FEWER OPERATIONAL CONSTRAINTS IN ZONE 5 AND ISSUED FEWER OPERATIONAL FLOW ORDERS THAN IN 2018?

A. No, the number of OFO constrained days limiting the Companies' intraday flexibility has actually increased. In 2019, Transco issued 198 days of OFOs affecting Zones 4 and 5, compared to only 68 days in 2018. From the period July 1, 2019 through February 29th—that is, the 8-month period following the implementation of the new restrictions—Transco issued 191 OFO days out of 244 days (~78%). Prior to the implementation of POS, most OFOs were limited to either over-burns or under-burns. Now, the majority of the OFOs issued since the implementation of POS simultaneously constrain both over- and under-burns.

IV. LOAD FACTOR UTILITIZATION ANALYSIS

Q. DOES THE LOAD FACTOR UTILIZATION ANALYSIS IN MR. LANDER'S TESTIMONY ACCURATELY REFLECT THE COMPANY'S DAILY GAS BURN AND FT UTILIZATION?

A. Mr. Lander's analysis uses the hourly daily operational estimated data supplied by the Company in response to SACE/CCL Data Request 1-7. However, the Company would reiterate, as previously stated in response to the data request, that this report contains daily and hourly usage <u>estimates</u> based on operational data flows sourced from each generating station. Additionally, the gas dashboard tool that aggregates this data was in the process of being developed and the Companies have learned that the tool did not access all the plant data during the entire review period. For example, there were units testing that did not have data available, and the tool was subject to various server and plant PI data outages during data transmission. These and other technical issues limited the accuracy of the operational data flows, reducing the accuracy of the information for the review period. Due to these technical issues, Mr. Lander's load factor utilization analysis does not include all gas flows and burns from the review period.

Q. ARE MR. LANDER'S CONCLUSIONS ABOUT THE COMPANIES' FIRM TRANSPORTATION UTILIZATION AND SHORT-TERM UTILIZATION ACCURATE?

No. Specifically, the capacity utilization factors calculated by Mr. Lander are not correct due to the data issues discussed above. SACE/CCL were also provided the final, actual consumption data based on end of month settlement reconciliations with the pipelines and allocated by station and unit. However, it does not appear that Mr. Lander used this data in his analysis. Using the Companies' actual total long term firm capacity plus the ad hoc nominal short-term capacity acquired over the review period, the capacity factor (load factor) utilization for the winter period was 88%, not

71% as stated by Mr. Lander, even while noting that Mr. Lander considered his under-calculated value of 71% to be “a very good level of utilization.”[5] The capacity factor for the review period averaged ~88%, not 64% as stated, again noting that Mr. Lander considered his under-calculated value of 64% to be “a good level of overall utilization.”[6] Lastly, the peak gas demand day was February 8, 2020, when the total gas usage was 1,500,000 dth (or 1.5Bcf), not 634,000 dth on November 12, 2019 as relied upon by Mr. Lander.[7]

As part of his utilization analysis, Lander suggests certain options that, in his opinion, are available to the Companies for procuring deliveries in excess of their firm contracted capacity, including: 1) short term contracted firm capacity; 2) segmentation of existing contracted capacity; 3) using their interruptible transportation (“IT”) capacity; or 4) using capacity held by sellers of gas to the Companies’ plants.[8] Assuming that Mr. Lander’s description of using “capacity held by sellers of gas to the Companies’ plants” refers to delivered third party supply, the Companies do purchase third party delivered gas and contract for short term firm capacity through the capacity release markets. Due to the operational constraints in Transco Zone 5, Transco customers are unable to segment firm transportation from North to South. Additionally, the Companies do not use IT capacity for delivery to any of their generation units given the need for reliable supply, which cannot be guaranteed given the interruptible nature of the product and the lack of availability when needed most

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[5] Direct Testimony of Gregory M. Lander p. 6, line 13.
[6] Direct Testimony of Gregory M. Lander p. 8, line 20.
[7] Direct Testimony of Gregory M. Lander p. 7, lines 10-11.
[8] Direct Testimony of Gregory M. Lander p. 8, lines 10-11.

in high gas demand scenarios. While interruptible supply may be sufficient in other industries, for example, manufacturing, it is not practical for ensuring the reliable supply of electricity to customers.

Q. WHAT WERE THE AVERAGE DAILY NATURAL GAS BURNS FOR THE PERIOD?

A. The average daily burns were 810,000 dths for the summer period and 795,000 dths for the winter period.

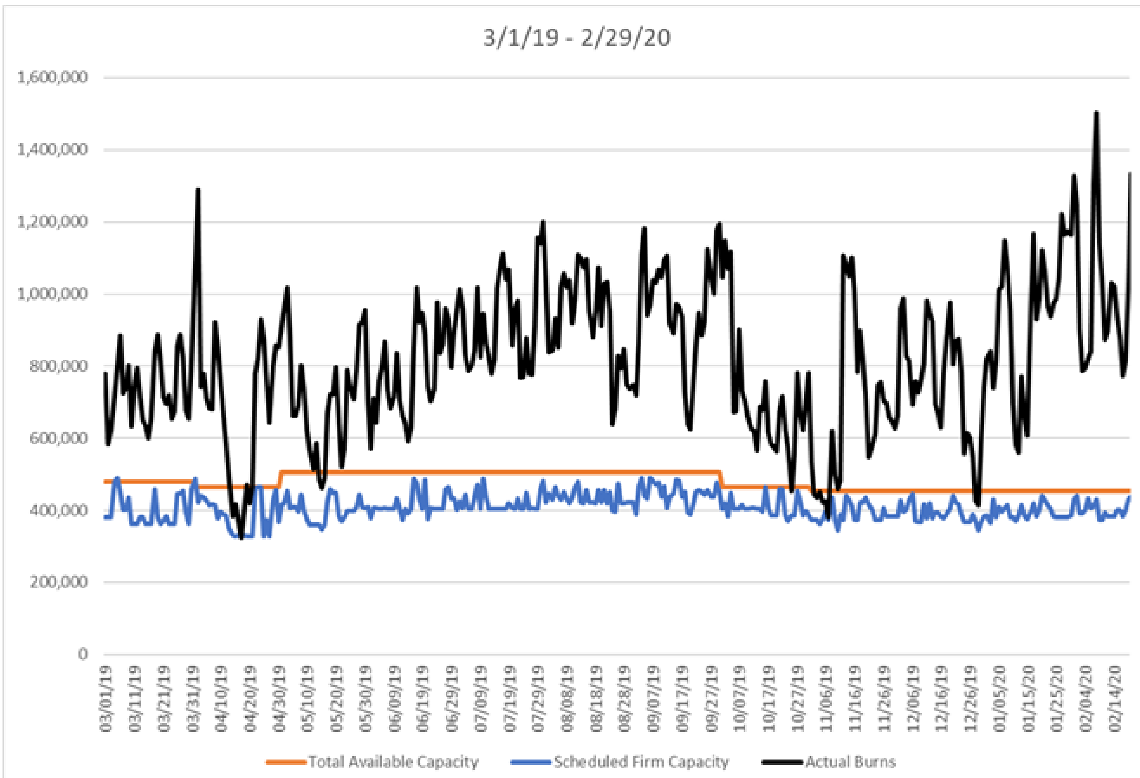

Figure 1: Firm Transport vs. Actual Gas Burn March 1, 2019 - February 29, 2020

As pictured in Figure 1 above, the highest burn was 1.5Bcf on February 8, 2020. All months had several days where burns exceeded 1Bcf/day, and the volume difference between the high and low daily burn during any one month ranged between 431,000 and 869,000 dths. This range manifests itself in the daily burn volatility each day.

Additionally, during the period, several new units with additional gas demand were testing and placed in service: 1) Belews Creek dual fuel unit with capacity up to 125,000 dth/day, 2) Clemson CHP with capacity up to 5,000 dth/day, and 3) Asheville Combined Cycle with capacity up to ~100,000 dth/day.

V. SUFFICIENCY OF CAPACITY TO SERVE COMBINED CYCLE UNITS

Q. IS MR. LANDER'S ANALYSIS OF HOURLY PEAK CAPACITY RELEVANT WHEN DETERMINING THE COMPANIES' CAPACITY NEEDS?

A. No. Transco does not hold shippers accountable for hourly ratable gas flows. Instead Transco's pipeline has **daily** constraints limiting overburn and swing service (based on volume of FT contracted) as stated in their Tariff, as well as strict nomination timeframes that do not allow for hour by hour scheduling adjustments or monetization of capacity on an hourly basis.[9] These operational constraints are measured at the end of each gas day, not on an hourly basis. Additionally, Transco assesses penalties for OFOs and POS based on gas day, not hourly flows as Mr. Lander implies with his local distribution company hourly peak swing service example.[10] Again, the Companies contract for 434,500/dth a day and do not have enough FT to meet their average or peak gas needs and therefore must rely on third party delivered gas, intra-day purchases, as well as, storage adjustments and unscheduled capacity to reliably meet their natural gas generation needs, all while protecting the customer from pipeline imbalance penalties of $50/dth.

Q. DO THE COMPANIES HAVE SUFFICENT FIRM CAPACITY TO SERVE

[9] *See* McClay Exhibit 1 for Transco Tariff Section 28 Nominations.
[10] Direct Testimony of Gregory M. Lander pp. 12-13.

THEIR GAS GENERATION REQUIREMENTS?

A. No, the Companies currently rely on a single source pipeline with an inadequate amount of FT and increasing operational restrictions limiting the gas burn flexibility that is needed by the Companies to respond to the plant burn deviations seen in daily operations. Over the review period, Transco Pipeline declared Bracketed OFOs on ~80% of the gas days and permanently changed the tariff to severely restrict daily overburns subject to $50 per dth penalties. The Transco pipeline has and continues to be inflexible, requiring the Companies to reserve available FT to manage their intraday swings in gas generation. This results in the Companies purchasing [redacted] who are also transporting gas on Transco subject to restrictions. Transco Zone 5 does not have accessible additional pipelines supplying the market area or accessible storage needed to manage a large portfolio of gas generation on a long-term reliable basis.

VI. <u>MONETIZATION OF UNUSED CAPACITY</u>

Q. DO THE COMPANIES AGREE WITH MR. LANDER'S RECOMMENDATION THAT THEY SHOULD BE REQUIRED TO MONETIZE THEIR UNUSED CAPACITY?

A. No, the Companies do not have extra capacity to monetize by releasing it to the market. As part of an overall gas supply strategy intended to benefit customers, the Companies purposely maintain FT capacity throughout the gas day to address intraday needs, late-cycle storage adjustments, and post cycle penalty mitigation. Due to their limited amount of FT, the Companies' strategy is to focus on protecting the customer from pipeline imbalance penalties of $50/dth rather than releasing limited daily capacity in exchange for nominal reward. As an example, if the

Companies were successful in reselling 10,000 dth of unutilized next day capacity to the open market at Mr. Lander's average price of two cents per dth/d,[11] the Company would see revenue of $200 (10,000 dth * $0.02). However, by not maintaining that unutilized FT capacity for its intraday needs, the Companies risk breaching either or both POS and OFO penalties. If the Companies overburned through the maximum POS or OFO tolerance for that same 10,000 dths, the Companies would be assessed a penalty of $500,000 (10,000 dths * $50). Per the Transco Tariff, capacity released for the next gas day, if released on a non-firm basis, would not be able to be called back at one hundred percent of the capacity that was released, and the timeframe in which it may be called back is prescribed by the Tariff and is not allowed on an hour by hour basis.[12]

Q. HOW DOES THE COMPANIES' FIRM TRANSPORTATION HELP TO MITIGATE POTENTIAL POS AND OFO PENALITIES?

A. One of the Companies' strategies to reduce customers' exposure to POS charges and penalties is to maximize its intraday FT utilization while ensuring gas supply for reliable electricity generation. Using technology, operational data is used to monitor the daily gas supply, hourly forecasted and actual gas burns, and OFO/POS volumetric limits. The gas desk utilizes the Companies' contracted Transco FT to manage supply intra-day by adjusting scheduled volumes as allowed by the Transco tariff's intraday scheduling deadlines. In order to meet intraday changes, the Companies utilize a combination of third-party purchases and FT over the full gas day through 8:00 pm, the

[11] Direct Testimony of Gregory M. Lander pg. 16, line 1.
[12] See Exhibit 1 Transco Tariff Section. 42.10 (c & d) Capacity Release.

ID3 scheduling deadline, to provide flexibility to the system and to avoid potential overburn or underburn penalties on the pipelines. Over the review period, the Companies made intraday supply transactions on [redacted] to meet their changing forecasted needs as permitted by Transco's nomination tariff, during the prior evening, ID1 and ID2 scheduling deadlines including weekends and holidays when the gas market is closed. Prior to the final intraday scheduling deadline at 8:00pm (Transco Tariff "ID3"), the gas desk schedules final supply adjustments using its remaining unscheduled FT to inject or withdraw supply from storage as the gas markets are closed. This is the last opportunity, per the Transco Tariff nomination schedule, for the Companies to schedule supply adjustments on the pipeline as the remaining 14 hours of gas burns are subject to variability due to forecast limitations and actual generation performance. During the period, the Companies utilized [redacted]

Q. WHAT OTHER WAYS IS THE COMPANIES' FIRM TRANSMISSION UTILIZED TO MITIGATE PENALTIES?

A. Lastly, at the end of the gas day at 10:00 AM, any of the Companies' remaining unscheduled FT can be utilized to reduce the over-burn volumes that cause POS charges and penalties. While retro nominations and post-cycle transactions may be available, neither is guaranteed, neither may be enough to mitigate penalties, and both are subject to market conditions where prices can be as much as 20% higher than the previous day.

Q. UNDER THE COMPANIES' GAS SUPPLY STRATEGY, HAVE THE COMPANIES INCURRED PENALTIES OF $50 PER DTH?

A. No, to date, the Companies have not incurred any penalties of $50 per dth.

VII. DISCOVERY AND PROCEDURAL MATTERS

Q. IS THE HOURLY GENERATION AND HOURLY GAS DELIVERY DATA REQUESTED BY MR. LANDER RELEVANT FOR HOW THE COMPANIES MANAGE TRANSCO'S PIPELINE REQUIREMENTS?

A. No, as discussed earlier in my testimony, Transco does not hold shippers accountable for hourly ratable gas flows. Instead Transco's pipeline has **daily** constraints limiting overburn and swing service (based on volume of FT contracted) as stated in its tariff and strict nomination timeframes that do not allow for hour by hour scheduling adjustments or monetization of hourly capacity. Therefore, the Companies manage their pipeline utilization on a daily basis to meet Transco's operational requirements. Despite this, the Company has endeavored to provide information consistent with that specified in the Commission's order in the 2019 DEC fuel proceeding and with the data requests submitted by SACE/CCL.

Q. DO YOU AGREE WITH MR. LANDER'S RECOMMENDATIONS THAT THE COMMISSION REQUIRE THE UTILITIES IN FUTURE FUEL CASES TO COLLECT AND PROVIDE FOR EACH GENERATION UNIT THE HOURLY GENERATION (MWH), THE UNIT TYPE, AND THE TYPE AND QUANTITY OF FUEL CONSUMED BY HOUR.

A. No, as noted above the Company has endeavored to provide information consistent with that specified in the Commission's order. However, this information is based on operational estimates and is not "revenue-grade," and is not recommended for use in either evaluating recommendations or making decisions that impact customer rates.

Additionally, in response to SACE/CCL data request 1-8 the Company provided the requested MWh of electricity production by plant by hour for the period March 1, 2019 through February 29, 2020 including the Unit Type[13] for all DEP units under review in this fuel proceeding. The Company also provided, in response to SACE/CCL data request 1-7, the requested hourly natural gas burn estimates. The Company did not provide its hourly daily fuel oil burn information as the Company does not operationally track this information in this format. Instead, as noted by Mr. Lander,[14] the Company provided the information it did have, i.e., the monthly consumption numbers that tie back to the monthly filed fuel reports.

As the Company has provided all the requested information it has available for production, it sees no reason for the Commission to take further action on Mr. Lander's recommendation.

Q. DO YOU AGREE WITH MR. LANDER'S RECOMMENDATION THAT THE COMMISSION ADJUST THE PROCEDURAL SCHEDULE TO PROVIDE FOR MORE TIME BETWEEN WHEN THE COMPANY FILES ITS DIRECT TESTIMONY AND WHEN INTERVENORS FILE THEIR DIRECT TESTIMONY?

A. No, it is my understanding that SACE/CCL submitted their first data request on April 10, 2020, which was several weeks before the Company's filing date of April 27, 2020 for direct testimony. I also understand that SACE/CCL had no substantive follow-up

[13] Direct Testimony of Gregory M. Lander p. 20, Table 1.
[14] Direct Testimony of Gregory M. Lander p. 17, lines 1-2.

discovery requests, apart from correcting a previously submitted data request.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes, it does.